06-12-09

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---- In the Matter of ----	)	PUC Docket No. 2008-0273
	)	
PUBLIC UTILITIES COMMISSION	)	
	)	
Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs	)	
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HAWAII RENEWABLE ENERGY ALLIANCE'S

POST-HEARING OPENING BRIEF

AND

CERTIFICATE OF SERVICE

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I. INTRODUCTION

By its Order filed on October 24, 2008, the Hawaii Public Utility Commission ("Commission") opened the instant docket, referred to hereafter as the "FiT" docket. The Commission, by its Order filed on November 28, 2008, granted the November 13, 2008 motion of Hawaii Renewable Energy Alliance ("HREA") to intervene in the FiT docket. HREA hereby submits this document, constituting its Post-Hearing Opening Brief on the FiT docket, dated June 12, 2009, to the Commission in accordance with the Commission's Order filed on January 20, 2009, as amended by the Commission's Order on April 27, 2009 and its letter on May 21, 2009.

HREA would like to note the following by way of introduction to our Opening Brief:

1. Intervenor and Party Settlement Discussions Subsequent to the Panel Hearing. Of the numerous issues identified on the FiT docket, HREA has identified and sorted the key issues into two tiers as follows:

    - First Tier (Overall Goals and Approach). Discussions focused on a phased approach: (i) starting with wind, solar and biomass as the eligible technologies, (ii) addressing grid integration issues via a modified Rules14H and a new rule for transmission level projects, (iii) addressing potential ratepayer impacts by limiting project sizes and total capacity by island, and (iv) clarifying the relationship of FiT to other acquisition methods, such as net metering and competitive bidding. Each limit is to be reviewed and adjusted as appropriate in subsequent phases.

- Second Tier (Ensuring Effective and Timely Implementation). While recent discussions have focused on "First Tier" issues, other issues while described here as "Second Tier," are nevertheless important. These include: (i) pricing criteria and methodologies, (ii) curtailment, (iii) renewable energy credits, (iv) applicability of FiT to existing non-FiT PPAs, (v) queuing, and (vi) program review and amendments.

2. Principles of Fit Design and Implementation. As stated in our Final Statement of Position ("FSOP"), filed on March 30, 2009, HREA believes the design and implementation of a FiT Program appropriate to Hawaii should be guided by a number of principles, such as, but not limited to the following:

   - Rapid Expansion of wholesale and retail renewable energy facilities and systems in support of the Hawaii Clean Energy Initiative ("HCEI") and related state energy objectives,
   - Achievement of this expansion at a reasonable cost to all ratepayers, considering lifecycle costing evaluations that include adjustments for risk associated with greenhouse gas emissions and other environmental impacts,
   - Implementation of a FiT program in a way that complements and supplements existing facilitation mechanisms, which include the competitive bidding framework, Schedule Q contracts, net metering, and tax credits and other incentives,
   - A Grid Infrastructure Program ("GRIP") which addresses grid integration and operation issues, such that renewables can be "plug and play,"
   - "No harm is caused policy" to existing and future renewable facilities,
   - A robust and "technology agnostic" market is created, and
   - Non-utility FiT solutions are emphasized while the utility focuses on its grid infrastructure.

3. Contents of our Opening Brief.

   a. In Section II, we present and discuss our Restated Final Statement of Position,

   b. In Section III, we provide a response to the legal questions as provided by the Commission on April 16, 2009, and

   c. In Section IV, we present our response to certain questions that were raised during the Panel Hearing, as described in the Commission's letter dated May 11, 2009 to the Parties.

Section II
HREA's Restated Final Statement of Position

A. Issues

Following discussions with other Parties during and subsequent to the Panel Hearing, including "settlement discussions" with HECO and a number of other Parties on June 3, 2009 at DBEDT, HREA's restated final statement of position ("RFSOP") on the issues as stated in the Commission's Order filed on April 1, 2009 is presented and discussed below.

I. Given the four existing renewable producer options (Schedule Q, net metering, competitive bid, and non-bid PPAs), what contributions can FiTs make toward achieving Hawaii's renewable energy goals?

HREA believes FiTs can play a key enabling role if they are designed and implemented addressing the spirit and intent of the seven principles as discussed in Section I. We offer the following comments on the specific role that existing renewable producer options have played in Hawaii:

<u>Schedule Q</u>

To date, HREA does not believe Schedule Q contracts have been much of a factor. First, until the last several years, avoided cost along with the price of oil has been low. Second, renewable projects, which are generally capital-intensive, have an economic of scale characteristic, such that smaller projects are more expensive. Hence, Schedule Q contracts have not been cost-effective options for many renewable producers.

As the price of oil has increased, payment rates are more attractive. Thus, for those customers that would prefer to "follow" the price of oil, Schedule Q might be a good option. However, since our state policy is now to de-link our purchases of renewable energy from the price of fossil fuel, i.e., avoided cost, the preferred policy option would be to convert Schedule Qs to FiTs.

<u>HREA Position on Schedule Q</u>. Thus, HREA strongly supports discontinuation of Schedule Q contracts in favor of FiTs. HREA also support offering existing Schedule Q suppliers the option of converting to a FiT.

Net Metering

Strictly speaking net metering is not a renewable producer option, i.e., one in which the producer sells renewable electricity to the utility. Specifically, the utility does not purchase power via a net metering agreement. Instead, net metering is actually a power exchange agreement. However, it is of great importance in this discussion, as net metered energy counts towards HECO's Renewable Portfolio Standards ("RPS"). As noted by WSB-Hawaii in its 2003 study[1], net metering was likely to achieve success over time as prices for renewable DG became more competitive and with continued support from state tax credits. In fact, 2008 was a banner year for PV with more Megawatts ("MW") installed than all the previous years combined, in large part due to the federal investment tax credit. Thus, net metering is on the threshold of even greater success with the extension of the federal tax credits through 2016.

HREA Position on Net Metering. Net metering offers a customer a cost-effective method for off-setting a portion of or their entire site load. Thus, given its success, HREA strongly supports continuation of net metering. HREA also supports FiTs as an option for those customers that wish to become net renewable energy producers and deliver net renewable electricity to the grid. In this case, a site load might also be served, but it would likely be a small fraction of the amount of electricity delivered to the grid. Finally, for those net metered customers that wish to "oversize" their system some, we support a "hybrid" approach where the customer enters into a FiT agreement to receive payment for the excess electricity to the grid on an annual basis.

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[1] Interim Report on "Renewables and Unconventional Energy in Hawaii," November 2003, WSB-Hawaii under contract to the Hawaii Energy Policy Project (see **http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf**)

Section II
HREA's Restated Final Statement of Position

Competitive Bidding

RPS was conceived on the mainland as a quota on wholesale energy delivery by electric utilities, e.g., the utilities were required to supply customers a certain percentage of their electricity from renewables, and that percentage was increased over time. The primary RPS implementation mechanism has been competitive bidding for proposals from non-utility entities. Competitive bidding has been quite successful in Texas and other states out of the 28 states and the District of Columbia that have RPS laws as of this date.

In Hawaii, our competitive framework was approved by the Commission in December 2006. Since then, the first competitive procurement under the framework was initiated in 2008 by HECO for up to 100 MW of "as-available" renewable energy on Oahu. Proposals were submitted and HECO indicated a goal for awarding one or more contracts by December 2009. So, how do we evaluate the pace and success of competitive bidding?

First, consider the following steps from start to completion:

a. HECO's time to prepare and issue the RFP (3 months-estimated),
b. Bidders time to prepare and submit proposals (3 months),
c. HECO's time to accept, review and select proposals for negotiation (4 months to the "short list"),
d. HECO's time to negotiate and sign contracts with winning bidders (per their schedule about another 11 months – January to December 2009),
e. HECO's time to prepare and submit signed contract package to the Commission and the Commission's to review and approve contract (3 months - estimated)
f. Total Time: on the order of two years.

Second, while potentially faster than the non-bid PPA process, we do not believe the pace rises to what could be deemed "rapid."

Third, regarding success, it remains to be seen how many contracts are awarded and for how many MWs of renewable power, and how many of those projects actually get financed and become operational.

Finally, there has been an apparent "unattended consequence" of HECO's implementation of competitive bidding, related to the projects that were under consideration by HECO and its subsidiaries before the implementation of the competitive bidding framework as follows.

We believe there were at least 17 projects exempted or waived from competitive bidding. While HREA had assumed HECO's goal was to rapidly and successfully conclude the negotiations of the various project proposals, the opposite result appears to be the case. Perhaps not all of these projects could be considered "shovel-ready," but it now appears that only a small number, perhaps three, that have signed contracts or are about to sign. These include First Wind's windfarm (30 MW) at Kahuku on Oahu, Keahole Solar Power (500 kW of Concentrating Solar Power) at the Natural Energy Laboratory near Kailua-Kona on Hawaii, and Tradewinds Biomass (estimated at 3.6 to 5.5 MW) on the Hamakua Coast on Hawaii. Keahole Solar Power and Tradewinds have signed contracts.

HREA Position on Competitive Bidding. HREA believes competitive bidding has a place, especially for larger projects, such as 50 MW and above, or when HECO has something very specific in mind. Without knowing the actual status of HECO's 100 MW RFP, we will have to "wait and see" how many projects actually come on-line. Then there can be an evaluation of the total costs of this specific process both in terms of the contracted payment rates for the renewable power and HECO's administrative costs.

We remain open to the results of that evaluation, but firmly believe that FiT can be a more effective acquisition method for projects up to at least 20 MW. We also request that the Commission conduct a review of the projects that have fallen by the "way-side." Some of these we believe meet the "shovel-ready" criteria, and we request that the developers of these projects be allowed the opportunity to continue or re-start, as appropriate, negotiations.

Non-Bid PPAs and PURPA

Implementation of PURPA in 1978 by the federal government and the state from the early 1980's through 2008 has encouraged those technologies that were most mature and cost-effective resulting in approximately 105 MW of renewable facilities in Hawaii, consisting of wind[2] (60 MWs), solar[3] (1.2 MW), biomass[4] (46 MW), geothermal[5] (30 MW), and hydro[6] (12^{+} MW).

As concluded by WSB-Hawaii in a study conducted for the Hawaii Energy Policy Forum in 2003[7], negotiations with the utility has required years under PURPA, in large part due to evolving interconnection requirements and their solutions, and contentious discussions on avoided costs. HREA notes, following the 1993 geothermal and hydro installations, a 13 period passed before the next facility, Hawi Renewable Development came on line in 2006.

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[2] The Kamao'a windfarm installed in 1987 at South Point (9.25 MW) has been shutdown and replaced with the Tawhiri, Pakini Nui windfarm (21 MW) at a nearby site at South Point. The Hawi Renewable Development windfarm (10.56 MW) at Hawi, Hawaii became operational in 2006. The First Wind Kaheawa Pastures windfarm (30 MW) on Maui became operational in 2007.

[3] The Lanai Sustainability Research LLC 1.2 MW PV facility became operational in 2008 on Lanai.

[4] Primary new biomass in this period was H-Power (46 MW) on Oahu became operational in 1990, and a land-fill gas (4 MW) at Kapaa Quarry also on Oahu. The latter is no longer in operation. H-Power's fuel is roughly 50% to 60% renewable, but all of H-Power's output counts towards HECO's RPS.

[5] PGV became operational in 1993 near Pahoa, Hawaii.

[6] The Wailuku River Hydro project (12 MW) near Hilo, Hawaii became operational in 1993. Per the HECO/CA's response, dated April 1, 2009 to PUC-IR-A (page 3), two other hydro projects became operational during this period: a 500 kW facility on Maui in 2006 and a 50 kW facility on Hawaii in 2008.

[7] Interim Report on "Renewables and Unconventional Energy in Hawaii," November 2003, WSB-Hawaii under contract to the Hawaii Energy Policy Project (see **http://hawaiienergypolicy.hawaii.edu/papers/bollmeier.pdf)**

The purpose of the instant discussion is not to assess blame, but merely to point out, as did WSB-Hawaii, that efforts to implement renewables in Hawaii have not "lived up to the intent and spirit of PURPA."

HREA Position on Non-Bid PPAs. Use of non-bid PPAs under PURPA in Hawaii has been a slow, contentious process. This is not to say that implementation under PURPA can't be successful. For example, significant windfarm development occurred in the 1980's in California with Standard Offer #4 Contracts. Why were they successful? The SO4's (as they were called) had standard terms and conditions, including standard prices. Essentially, in our opinion, SO4's were feed-in tariffs. Consequently, we believe one significant role FiT can provide is to reduce the time required to acquire new renewable resources, as been proven in Germany, Spain and other countries.

HREA Position on the Purpose of FiT

HREA supports the following as the purpose of FiT:

> The purpose of feed in tariffs is to accelerate the acquisition of renewable energy by the HECO Companies to help achieve the HCEI goal of reducing Hawaii's dependence on imported fossil fuel by meeting at least 70% of the State's energy needs with clean renewable resources by 2030.

HREA believes FiT is a superior methodology to meet a portion of Hawaii's clean energy and energy independence goals. Summarizing the discussion above, we believe FiTs can replace or supplement existing renewable producer options as follows:

1. Replace Schedule Q contracts,
2. Provide an option to net metering and in conjunction with net metering a mechanism for payment of excess renewable electricity delivered to the grid,
3. Provide an option to exemptions from the competitive bidding framework, i.e., under 5 MW on Oahu and roughly 3 MW on both Maui and Hawaii, and

4. Provide an option to non-bid PPAs. Note: there does remain the legal question as to whether, under PURPA, FiTs can replace non-bid PPAs (See our response in Section II on this and other legal issues).

<u>What is the potential for FiT in Hawaii?</u>

This is a multi-faceted question that is difficult to answer. First, to make it easier, let's make the following assumptions about the design and implementation of FiTs:

1. what technologies are eligible, and any limits that might be placed on project size or the total amount of projects per island, and the FiT payment rates,
2. whether any physical limitations are placed on the penetration of renewables on our island grids, and
3. whether the HCEI goals of attaining 70% renewable energy from renewables by 2030 continue to be the state policy.

Given the above and without regard to timelines, the potential for FiTs is significant. Consider the following:

1. The HECO's the current peak demand is on the order of 1,600 MW[8],
2. Assume wind and solar are the only eligible technologies, and as as-available their average capacity factor is 25%,
3. An initial feeder circuit limit is 15%, but is expanded to 50% over time on each of the HECO system 400 circuits,
4. An initial transmission-level limit of 15%, and expanded to 50% over time,
5. Initial transmission limits are expanded to 50% on Maui and Hawaii over time,
6. FiT payment rates are established that are fair to the developer/customer and approved as "just and reasonable" to ratepayers,

[8] Assuming current peak demand is approximately 1,200 MW on Oahu, 200 MW on Maui, 200 MW on Hawaii, 6 MW on Molokai and 6 MW on Lanai for a total of 1,612 MW.

The two following charts indicate that there are two market sizes based on the twin assumptions expressed in items 3 and 4 above as follows.

Summarized in the table below, Case I assumes a limit for distribution feeder circuits of 15% of feeder peak loads in MW on all islands, and transmission level projects on all islands of 15% of system peak loads. The results show a total market of 424 MW with an annual output of 927,684 MWH/yr or approximately 9% of HECO's current sales of 10,000,000 MWH/yr.

	Peak	Markets in MW			
Island	Load	Distribution	Transmission	S-Totals	MWH/yr
Oahu	1200	180	180	360	788,400
Maui	200	30	0	30	65,700
Hawaii	200	30	0	30	65,700
Molokai	6	0.9	0.9	1.8	3,942
Lanai	6	0.9	0.9	1.8	3,942
Totals	1,612	242	182	424	927,684

Summarized in the table below, Case II assumes a higher limit for distribution feeder circuits of 50% of feeder peak loads in MW on all islands, and transmission level projects of 50% of system peak loads on in MW on all islands. The results show a total market of 1,612 MW with an annual output of 3,530,280 MWH/yr or about 35% of current HECO system sales of approximately 10,000,000 MWH/hr.

	Peak	Markets in MW			
Island	Load	Distribution	Transmission	S-Totals	MWH/yr
Oahu	1200	600	600	1200	2,628,000
Maui	200	100	100	200	438,000
Hawaii	200	100	100	200	438,000
Molokai	6	3	3	6	13,140
Lanai	6	3	3	6	13,140
Totals	1,612	806	806	1,612	3,530,280

Conclusions. HREA notes that Case I represents a near term opportunity based on HECO's distribution circuit criteria of 15%, which we have applied to the transmission level projects as well. We believe with the appropriate design and implementation of FiTs this market could be met in an initial implementation phase two years. Case II is a longer term opportunity based on implementation of grid infrastructure improvements, as necessary, in order to allow feeder circuit penetrations of 50% on all islands

HREA notes in Case I the focus is on distribution feeders on all islands, and on transmission level projects on Oahu, as the penetration of transmission-level projects already exceeds 15% on Maui and Hawaii. Thus, in Case II the markets are opened further by increasing the distribution feed and transmission-level penetration limits.

Finally, HREA believes that the approach for Case I is conservative. Case II might be construed as a "stretch" goal, much like the overall HCEI goal of 70%. And HREA recognizes that the 50% penetration limits for Oahu may not be realistic, if the cable system becomes a reality. If it doesn't, at a minimum Case II serves as a "back-up" approach to the cable. Moreover, subject to further study and implementation of grid infrastructure improvements, it may be possible to increase the penetration criteria for Case II further.

Section II
HREA's Restated Final Statement of Position

II. What are the physical limitations on the utility's ability to purchase renewables?

Introduction. We now understand the joint HECO/CA position to include the following key elements related to physical limitations:

1. Eligible Technologies: wind, solar and in-line hydro,
2. Maximum Project Size: 500 kW or as limited by:
    a. the distribution feed circuit criteria of 15% (ratio of all DG on the circuit to the circuit peak load), and
    b. interconnection requirements studies, as required, for transmission-level projects.
3. Island Total Market in MW: no specific CAPs have been proposed by the HECO/CA , but we anticipate the HECO/CA may propose island limits in their Opening Brief

Discussion. Per HREA principle "d," HREA believes all real integration impacts must be addressed by the utility in collaboration with industry in developing and implementing a Grid Infrastructure Plan ("GRIP") for each island. We believe over the long term, as we move towards the "Smart Grids" of the future, technical solutions primarily in the form of ancillary services and other measures will be identified and implemented. From our response to HECO/HREA-IR-4 on March 13, 2009:

> "We propose that the utility provide all ancillary services to insure that reliability and power quality are maintained on each island. Given that, the FiT program can work more efficiently and effectively to accelerate the deployment of renewables in the islands. As a back-up, on a project by project basis, if the utility and developer agree that a project-specific ancillary services component is desirable, the developer could provide the services as an "adder" to the basic FiT or on a separate FiT.
>
> However, it is still our belief that the more cost-effective approach will be for the utility to identify key locations in its grids where the appropriate technology (such as a battery-inverter system) should be deployed, and to do so as rapidly as possible."

With the evolving HCEI, there are significant potential grid infrastructure costs, e.g., the cable system that would interconnect Oahu with Maui. With a cable system, the affected grids begin to take on the aura of a larger "central station" grid with Big Wind projects dispersed on Molokai and Lanai. Furthermore, in the WSB-Hawaii report, an assessment of the efficacy of DG versus CG ("Central Generation") by Loudat and Associates[9] concluded the following:

> "The report presents a framework allowing the assessment of the economics of power generation transitions. The qualitative aspects of this framework demonstrate the breath required for a comprehensive economic analysis of this transition. Since the framework is quantitative it also allows a preliminary investigation of the economics of meeting incremental power demands transitioning from central generation capacity to distributed generation capacity. Adapting and subsequently using the model for a ***preliminary analysis of Oahu incremental power demands through 2023 indicates that there are power cost savings,*** which lead to consequent economic and fiscal benefits to maximizing power from DG.
>
> Even though the results are preliminary, they support the contention that every measurable policy goal is improved by utilizing DG given the base assumptions regarding current technology, efficiencies, costs and emission in the Hawaii Energy Transition Model. ***The numerous options tested in the model all demonstrate a uniform advantage for DG derived power***. Since DG technologies are in the early part of the learning curve, further DG improvements can be anticipated as deployment increases. The recent blackout in the North East and Canada stretching from Toronto to New York shows how system vulnerability due to system surges, extreme weather or terrorist actions will improve as the potential for DG is realized. ***Power quality will also improve by moving towards a hybrid of CG and DG power systems.***
>
> The *prima facie* evidence from our analysis that supplying approximately 80 percent of Oahu's power need from CG may no longer be optimal suggests that similar analysis holds true for the other counties in Hawaii. It is clearly important to revisit and reexamine Hawaii's regulatory environment for the utilities industry, the structure of institutional incentives for non-conventional and renewable fuels, refinery and transportation constraints, and constraints imposed by resource capacity and community acceptance. Siting of co-generation facilities in the State and power procurement are other candidates demanding immediate attention in order to facilitate the emergence of green power in the State. The time appears to be propitious for making the transition to *soft energy paths."*

[9] Appendix J to the Interim Report, entitled: "The Economics of Transitions to Heat and Electricity Generation through Non-Conventional and Renewable Fuels," prepared by Drs. Tom Loudat and Prahlad Kasturi.

Thus, while the cable system can bring certain benefits, HREA believes we must focus on opening the DG market in order to achieve a balance between CG and DG. In short, HREA believes the increased levels of renewable DG will have positive impacts on grid reliability, stability and operation[10].

Finally, HREA believes the overall issues of how much CG vs. DG will ideally be best resolved in the utility's new IRP process (reference newly-opened docket no. 2009-0108).

HREA Position on Physical Limitations. In discussions following the Panel Hearing, HREA appreciates that it may be prudent to introduce certain physical limits during the initial implementation phase of the FiT program to ensure grid integrity and reliability. Secondarily, this phased approach would also serve to limit program costs and provide time and information to address questions of the overall costs and benefits of FiT. HREA is committed to working with HECO, the CA and the other parties to resolve the issue of physical limitations.

That said, HREA believes there is sufficient evidence for the Commission to approve a FiT program based on a phased approach as follows:

1. Phase I – first two years of the Fit Program:
    a. Limit eligible technologies to wind, solar and biomass,
    b. Limit project size to 5 MW on Oahu, 3 MW on Maui and Hawaii,
    c. Limit total penetration of all DG (including existing and new projects) on distribution feeders to 15% of feeder peak loads,
    d. Limit total penetration of transmission level projects via Independent Power Producers ("IPPs") on Oahu to 15% of Oahu's peak load,

[10] HREA would also like to note supporting evidence presented by the Solar Alliance in their response to HECO/Solar Alliance-IRs-4 and 5 that implementation of a FiT program, such as the Proposed FiT Tariff will improve system reliability and power quality.

e. Allow new transmission level projects elsewhere based on the results of Interconnection Requirements Studies ("IRSs") and other factors,

f. Utility will either cover the costs to design, install and operate any ancillary services, and

g. Complete island grid studies to identify: (i) areas where penetration limits can be relaxed, and (ii) as necessary, grid infrastructure improvements.

2. Phase II – second two years of the Fit Program
   a. Include additional technologies based on evidence to support proper pricing,
   b. Increase project size limits to 10 MW on all islands,
   c. Increase total penetration of DG to 30% on distribution feeders,
   d. Increase total penetration of transmission level projects to 30%,
   e. Implement identified grid improvements and continue grid studies as appropriate, and
   f. Integrate the grid studies with the new IRP,
3. Phase III and beyond – to be determined based on the first two phases with the following goals:
   a. Increase list of eligible technologies,
   b. Increase project size limits to 20 MW,
   c. Increase penetration limits to 50%, and
   d. Continue grid improvements.

III. What are the appropriate criteria for eligibility to sell under FiT tariffs?

Introduction. As in our response to II, we understand the joint HECO/CA position to include the following key elements related to eligibility:

1. Eligible Technologies: wind, solar and in-line hydro,
2. Maximum Project Size: 500 kW or as limited by:
   a. the distribution feed circuit criteria of 15% (ratio of all DG on the circuit to the circuit peak load), and
   b. interconnection requirements studies, as required, for transmission-level projects.
3. Island Total Market in MW: Perhaps to be discussed in the HECO/CA opening brief, and
4. Ownership: Neither HECO, nor its affiliates HELCO and MECO, are seeking to be eligible for FiT agreements. It is not clear, however, if HECO might consider establishing an unregulated affiliate to compete with industry on the FiT.

Discussion. Generally, HREA supports opening the FiT market to all technologies. However, HREA understands and agrees with the HECO/CA that the key criteria for determining which technologies should be eligible for FiT include those technologies that are commercial, and especially those that have already been deployed in Hawaii, and for which there are sufficient data and information for proper pricing of the FiT payment rates. We do not believe the FiT should be used to support technologies that are still in the R&D phase. As a better alternative, HECO should support emerging technologies and, in fact, are doing so. For example, HECO has entered into negotiation for non-Bid PPAs for a wave project on Maui and an OTEC project on Oahu.

HREA's Position. HREA believes the phased approach discussed in our response to Issue II best addresses the inclusion of all commercial technologies by opening the market over time to additional technologies. At the present time, we believe there are sufficient data and information for pricing of wind and solar (including both PV and concentrating solar power). We remain open to proposals on other technologies such as biomass and hydro, should sufficient data and information be provided for proper pricing of biomass and in-line hydro.

To be clear, HREA recommends that the Commission consider tentatively approving additional technologies, such as biomass and in-line hydro, subject to the caveat that one or more Parties provide pricing data and information during the next phase of this proceeding which we understand will be the preparation of the FiT tariff.

IV. What decisions are necessary to ensure that FiT rates are just and reasonable, as required by Hawaii law?

Introduction. We believe there is an emerging consensus that sufficient pricing data and information are needed in order to determine proper pricing for eligible FiT technologies, but not on the specific technologies for which that data and information exist. Likewise, there is no consensus among the Parties as to whether implementation of FiTs would result in a net "subsidy" to be paid by all ratepayers. So, at the present time there is a conundrum as to:

1. how to price specific FiT technologies,
2. whether said prices result in a subsidy, and
3. whether a subsidy, if it exists, can be considered "just and reasonable."

HREA believes the issue of subsidy cannot be resolve until an independent cost-benefit study of FiT has been conducted and reviewed. We have stated for the record in our responses to HECO/HREA-IRs-7 and -8 on March 13, 2009, that we do not believe there would be a net subsidy. Rather than reiterating those responses here, we would simply state that we look forward to reviewing to the results of an independent cost-benefits study on FiT.

Discussion. In the meantime, we would like to discuss pricing criteria and methodologies, and the policy context within which we should be evaluating proposed FiT rates and their potential subsidies.

Regarding pricing criteria and methodologies, we provided the following description of two potential pricing methodologies in our data and information filed on May 8, 2009:

> "1. Brief Discussion of Alternative Fit Payment Rate Methodologies. HREA observes that there are at least two alternative Fit payment rate methodologies. By methodology, HREA means a general approach by which theoretical and empirical data and information can be used to propose FiT payment rates. We have identified two specific approaches that are best characterized by the initial source of data and information, i.e., Non-Hawaii vs. Hawaii. These two approaches are described below.
>
> a. Non-Hawaii-based. In this methodology, detailed data and information from wind projects on the U. S. mainland, Europe or other wind project locations are analyzed to establish "generic" costs for wind projects of various sizes. These estimates, in turn, are adapted to Hawaii to account for the differences in installed costs (including differing land or site acquisition costs), operating and maintenance costs, performance and anticipated developer profits. There can also be alternative business models which, in turn, may be related to differences in government incentives, such as tax credits, in Hawaii. In some cases, there may be relevant studies that summarize wind or other renewable projects[11]. If so, this may facilitate the accumulation and analysis of the data and information from existing projects. Either way, a certain amount of judgment is required to adapt the generic data and information to Hawaii. For example, it may not be as simple as applying an "adder" to such cost data to provide a realistic estimate of the costs for similar projects in Hawaii. However, it may be realistic to conclude, based upon empirical evidence, that in general the cost of shipping a U. S. manufactured wind turbine to Hawaii is 30% greater than shipping to other U.S. mainland locations, labor costs in Hawaii are 20% more, etc. HREA believes this approach is viable, if there is a high level of confidence, for example, in a data set from recent projects in California or other states. These data, in turn, could provide a basis for an assessment of what wind projects should cost in 2009 in California, and thus be adapted to produce cost estimates for Hawaii in 2009.
>
> b. Hawaii-based. In this methodology, data and information on existing or planned projects in Hawaii are used as a starting point for the estimates of the FiT payment rates. One obvious advantage of this approach is that existing costs are real and do not have to be adapted from costs in another locations. On the other hand, one obvious disadvantage occurs if there are a limited number or no existing projects in some project sizes of interest in Hawaii, while there may be good data on the mainland. For example, there are good data on the costs of existing windfarms in Hawaii and potential windfarms that are under development. On the other hand, there is a relative paucity of data on smaller windfarm projects. This shortcoming can be overcome to a degree if there a bonafide offers to review.
>
> As with the Non-Hawaii-based methodology, future costs must be estimated given current trends in wind turbine costs, performance and anticipated business models.

[11] For example, the USDOE Lawrence Berkeley Laboratory conducted a survey of U. S. wind project costs for 2007. See http://eetd.lbl.gov/ea/ems/reports/lbnl-275e.pdf.

> That said, HREA has decided to employ the Hawaii-based approach, as we believe we have sufficient data and information and on existing and planned projects to provide a viable wind FiT payment proposal which is discussed below."

HREA notes that these methodologies both include cost-based pricing criteria. That is, the FiT payment rates are based on the project costs and a fair rate of return on investment. The FiT payments are expressed in cents per kWh, and are escalated over time by a set percentage.

Finally, please find a report attached as Exhibit A, entitled "US Solar PV Cost Trends and Analysis, April 16, 2009, authored by Thomas Maslin. HREA is providing this report as: (i) promised by Ms. Jody Allione during the Panel Hearing, and (ii) a supplement to data and information provided by HSEA and the Solar Alliance. By way of introduction we offer the following comments:

1. The report includes cost data for mainland projects that are not adjusted for Hawaii,
2. While that report does not talk about specific profits or rate of return levels, HREA believes developers should have a rate of return not less than HECO's guaranteed 10.6% adjusted for developer risk, and
3. The methodology for the PV cost recovery and incentives for investors (including how tax credits are handled) should be worked out between the utility and the interveners for the FiT rate development.

Regarding the <u>policy context within which we should be evaluating proposed FiT rates and their potential subsidies,</u> we have reflected on the guidance regarding costs as provided in HRS § 269-27.2(d), which is inserted below:

> "(d) Upon application of a public utility that supplies electricity to the public, and notification of its customers, the commission, after an evidentiary hearing, may allow payments made by the public utility to nonfossil fuel producers for firm capacity and related revenue taxes to be recovered by the public utility through an interim increase in rates until the effective date of the rate change approved by the commission's final decision in the public utility's next general rate proceeding under section 269-16, notwithstanding any requirements to the contrary of any other provision in this chapter or in the commission's rules or practices; provided the amount recovered by the utility

> and the amount of increase in rates due to the payments for firm capacity and related revenue taxes to be charged to the consumers of the electricity are found by the commission to be:
> (1) Just and reasonable;
> (2) Not unduly prejudicial to the customers of the public utility;
> (3) Promotional of Hawaii's long-term objective of energy self-sufficiency;
> (4) Encouraging to the maintenance or development of nonfossil fueled sources of electrical energy; and
> (5) In the overall best interest of the general public."

We believe the Parties have talked some about what is "just and reasonable" [number (1) above] and what is a "fair" payment to the FiT provider, and in general terms, about payments that are "not unduly prejudicial to the customers of the public utility" [number (2) above].

However, in our opinion, we have not really talked much about the overall policy context, i.e., numbers (3) to (5). Yet, while everyone may support the benefits as expressed in numbers (3) to (5) above, it is arguably harder to decide whether a specific payment tests the number (1) and number (2) criteria, e.g., the proposed payments are too high, e.g., they are not "reasonable" as they are "unduly prejudicial to customers." Furthermore, if we agree the benefits are "just", does that make the decision easier?

Some might say the answer is blowing in the wind or shining in the sun. Others might say, it is facing up to the reality that oil is a limited resource whose cost is only going to go up over time. To be clear, we have not heard any of the Parties suggest that long term oil prices will be trending downward. However, while the hedge value of renewables looks really good, with price volatility we believe ratepayers will ultimately have "no regrets" about a rapid deployment of renewables. Why? A major benefit of renewables is that their costs will be known, a vastly superior attribute compared to our conventional, oil-dependent resources. Still, when faced with the dilemma that we may not have all the information we would like in order to make a decision, how do we proceed. HREA believes we proceed in recognition that the "level of confidence" in our decision-making is not as high as we would like. We proceed because we believe that action is warranted and that we can "live with our decision," which is based on what we believe is the best evidence or information available to us at the time.

Section II
HREA's Restated Final Statement of Position

HREA Position. In summary, HREA believes the tough decisions to be made by the Commission to ensure that FiT rates are just and reasonable can be broken down into the two distinct stages: (1) approval of the basic principles or framework for the Fit program, and (2) approval of the FiT tariff as follows:

1. FiT Program Framework, assuming a phased approach:
    a. Eligible technologies,
    b. Project size CAPs (if any),
    c. Island capacity CAPs (if any),
    d. Program cost CAPs (if any), and a cost-benefit study of the FiT program,
    e. Interconnection requirements (distribution and transmission levels),
    f. Program implementation steps (independent oversight, tariff format, application and queuing procedures, review and evaluation approach, timelines, etc.)
2. FiT Tariff:
    a. Interconnection requirements,
    b. General terms and conditions,
    c. Payment rates, broken down by technology and capacity blocks, and taking into consideration available state and federal tax incentives, and curtailment[12].

HREA believes there are sufficient data and information for determining a "just and reasonable" payment rates and recommend that the Parties be directed to work collaboratively to prepare a stipulated FiT tariff for the Commission's approval. There will be opportunity for Parties to supply additional cost data and information. Ultimately, we believe the Commission's job while challenging is tractable. We respectfully request the Commission also consider that Hawaii is uniquely positioned to take advantage of significant state and federal tax incentives that will help us build on the momentum already created in our renewable market.

[12] HREA supports payment for curtailed FiT electricity. However, we defer to Tawhiri as to the reasons why and how curtailed electricity should be compensated.

V. What non-rate terms are necessary to make FiTs just and reasonable?

Introduction. HREA believes there may be an emerging consensus on some non-rate terms, and will simply indicate our position on certain non-rate terms.

HREA Position. HREA supports the following non-rate terms as described below:

1. Term of FiT Agreement. HREA supports a 20-year term for FiT agreements. That said, we have proposed a 10-year term for residential and small-commercial wind FiTs, and thus believe shorter terms should be available upon request;
2. Legal Content of the FiT Agreement. HREA supports the FiT agreement as a "one-stop" agreement, including all necessary legal rights and obligations. For example, the FiT agreement should combine the elements of both a power purchase agreement and an interconnection agreement;
3. Compensation after FiT term conclusion. HREA supports an option for extension of the FiT beyond its terms, e.g., 20 years. HREA supports a one-time 5-yeare extension, or at the option of the FiT provider, the right to negotiate a new FiT or other power purchase alternatives that may be available at that time; and
4. Renewable Energy Credits ("RECs"). HREA supports provision of the initial ownership of the RECs associated with a FiT Project to the owner of the project. Given that, the owner is free to market or trade the project's RECs however he chooses. Note: in pricing the FiT payment rate, the potential value of RECs should not be included at this time, in large part given the uncertainty in the value and marketability of RECs in Hawaii.

VI. Utility cost recovery: what principles should apply?

Introduction. HREA believes there may be an emerging consensus on some utility cost recovery principles and will simply indicate our position on certain utility cost recovery principles.

HREA Position. HREA supports the following utility cost recovery principles:

1. FiT Payment Cost Recovery. Since FiT is a type of power purchase agreement, HREA supports HECO's timely recovery of FiT payment through the Energy Cost Adjustment Clause ("ECAC") as with current renewable PPAs; and
2. Alternate FiT Payment Cost Recovery Methods. HREA can also support what may become a preferred payment method, i.e., a special FiT Program Surcharge or including FiT payments as part of the Clean Energy Infrastructure Surcharge. The rationale for either of these methods would be to facilitate transparent accounting of HECO expenditures in support of the HCEI.

VII. What are the appropriate processes for accepting and interconnecting FiT projects?

Introduction. HREA observes there is movement towards consensus on some elements of this issue set, especially with respect to Rule 14H for interconnecting DG. In the case of transmission level project, in HREA's opinion, for FiTs to work for larger project an equivalent Rule XYH needs to be developed for transmission level projects, and this has not been discussed.

With respect to the application process and specifically as to how queuing should work, HREA supports a queuing process that is based on a "first-ready, first-to-interconnect " basis. We understand there are at least two models for this type of approach: (i) the queuing procedures adopted by the Midwest Independent Transmission System Operator, Inc., and (ii) the queuing process employed on the California Solar Initiative. However since the Panel Hearing, HREA was not able to discuss the queuing process with other Parties. Therefore, HREA will simply indicate our position on the issues.

Section II
HREA's Restated Final Statement of Position

HREA Position. HREA supports the following process as appropriate for accepting and interconnecting FiT projects as described below:

1. Queuing Process – All Projects. It is now quite clear than a properly-designed and functioning queuing process is going to be one of the keys to success in the implementation phase. First, we recognize that there is not only a queue for FiT projects, but also for net metering, non-bid and competitive bidding processes. HECO needs to staff up in order to process all applications for each of these four queues. Given this challenge, we recommend the Commission hire an Independent Oversight Manager to manage the queuing process. In essence, the manager would straddle the gap between the developers and the utility and be responsible for the transparency and orderliness of the process while enhancing and coordinating the resources of the utility in implementing the FIT. This would include:

    a. Reviewing the qualifications of the applicants and their applications,

    b. Managing and coordinating the queues for all four processes described above,

    c. Monitoring the application and qualification process, including interconnection requirements and sub-queues for interconnection requirements studies,

    d. Ensuring transparency and overall fairness of all phases of process in order to reinforce the market signal; and

    e. Establishing and maintaining an ongoing status reporting system in an accessible network for interested developers. The reporting system would be used to identify and track projects by type and the size, and projects in the queue by location.

    Note: this manager could be paid in a similar fashion to the Public Benefits Plan administrator or by the fees paid into the queues by the applicants

2. Interconnection Process – Distribution Level Projects. Customer-Side. Projects must meet requirements as specified in utility Rule 14H as modified (TBD) for FiTs. For the FiT implementation, HREA supports the following. Specifically, for projects up to 5 MW, projects will be considered "plug and play," and hence there would be NO:
    a. performance standard requirements (e.g., ramp rate restrictions) for projects,
    b. fault ride-through requirements for projects; and
    c. utility monitoring (SCADA) and control of individual project.

    Note: should the utility require any ancillary services during the Phase I implementation, the utility will either: (i) pay for, or (ii) negotiate a separate agreement with the FiT provider for ancillary services. In subsequent Phases, the utility would cover all costs for ancillary services. To be clear, ancillary services will include but not be limited to: frequency regulation, voltage support, peak shaving, load shifting, black start capability and VAR support
3. Interconnection Process – Transmission Level Projects. Similarly, projects must meet basic interconnection requirements as specified in the utility "Rule XY," as developed in the FiT docket. Projects up to 5 MW would be considered "plug and play" as in 2 above. HREA understands and appreciates that the required infrastructure improvements may not be identified and implemented during the first Phase (i.e., first two years). Therefore, the timeline for full implementation may need to be delayed. Until then, the following existing interconnection requirements must be met for projects larger than 5 MWs, but no larger than 20 MWs:
    a. Performance standards (e.g., ramp rate restrictions),
    b. Fault ride-through requirements, and
    c. Utility monitoring (SCADA) and control.

    Note: see note above in section 3.

VIII. If the Commission does approve FiTs, what actions can it take to keep total costs reasonable?

HREA Position. As discussed in our response to all previous issues, but particularly Issues I to IV, HREA recommends a phase approach to implement FiT as a means for achieving a rapid, successful deployment of renewable energy projects in Hawaii. The phased approach takes into consider the two overall key issues, regardless of which technologies and entities are eligible for FiT tariffs. These key issues are interconnection requirements and program costs.

During Phase I (first two years), implementation will be limited physically in terms of project size to 5 MW and perhaps by the amount of total capacity by island, yet to be determined. These limitations are driven initially by grid penetration criteria at the distribution and transmission levels, while grid studies are conducted in parallel to determine how the limits can be relaxed and what infrastructure improvements would be needed to increase the limits.

The initial physical limitations also serve to limit the initial program costs. Similarly, during the first phase a cost-benefit study should be conducted to determine if any real subsidy results from the implementation of FiT. If so, the results can be used to adjust program goals in subsequent phases of implementation. If not, the program can be expanded subject *only* to a re-evaluation of physical limits or constraints to FiT

B. CONCLUSION

Given our long-standing state goals to increase our use of renewables and now the HCEI, HREA believes that FiT is an excellent addition to our implementation portfolio, which includes and should continue to include competitive bidding and net metering. We believe FiT has the potential, if appropriately designed and implemented, to take implementation (or deployment) of renewables in Hawaii up to a whole new level based on, but not limited to, the following principles:

- Rapid Expansion of wholesale and retail renewable energy facilities and systems in support of the Hawaii Clean Energy Initiative ("HCEI") and related state energy objectives,
- Achievement of this expansion at a reasonable cost to all ratepayers, considering lifecycle costing evaluations that include adjustments for risk associated with greenhouse gas emissions and other environmental impacts,
- Implementation of a FiT program in a way that complements and supplements existing facilitation mechanisms, which include the competitive bidding framework, Schedule Q contracts, net metering, and tax credits and other incentives,
- A Grid Infrastructure Program ("GRIP") which addresses grid integration and operation issues, such that renewables can be "plug and play,"
- "No harm is caused policy" to existing and future renewable facilities,
- A robust and "technology agnostic" market is created, and
- Non-utility FiT solutions are emphasized while the utility focuses on its grid infrastructure.

DATED: June 12, 2009, Honolulu, Hawaii

Exhibit A to Section II

US SOLAR PV Cost Trends and Analysis

April 16, 2009

emerging energy research

Data Insight

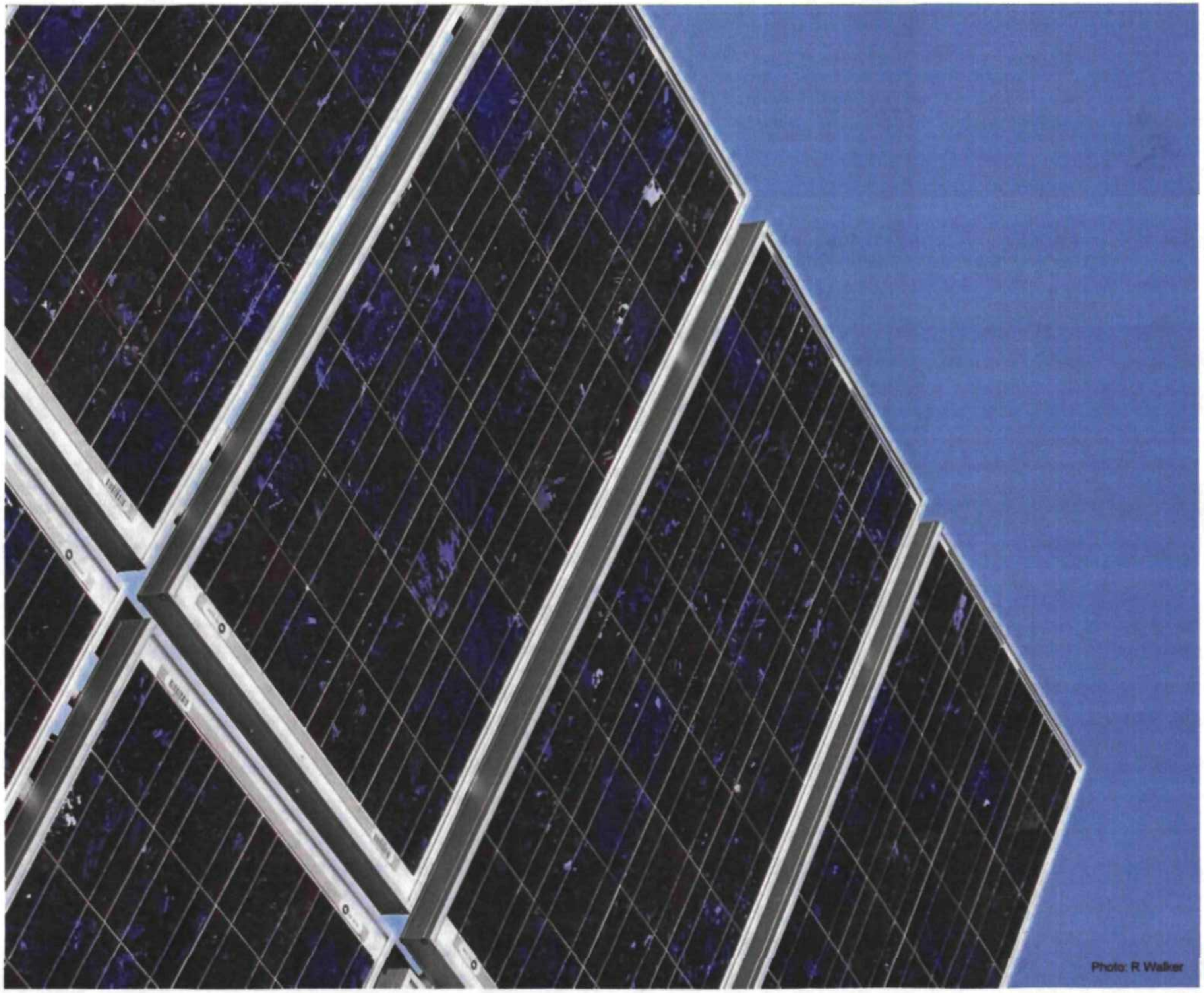

Photo: R Walker

North America Solar Power Advisory

ID# NAS 645-090416

US Solar PV Cost Trends and Analysis

16 April 2009

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Summary

Shifting PV incentive regimes in Europe and the US have created near-term price volatility, giving project developers an advantage over suppliers

- A forecasted 2.3 GW drop in capacity added in the Spanish PV market from 2008 will not be offset by rising global markets Italy, Greece, France, or the US until 2010. As a result, suppliers will have excess capacity, pushing prices down
- Extension of the federal Investment Tax Credit (ITC) in 2008 and the 2009 Economic Recovery Act are catalyzing the scaling of US PV development, with utilities playing a leading role in driving down installation costs through large-scale system purchases planned for 2010 and 2011

Delivered cost of electricity for PV systems in the US is significantly declining for the first time in four years, with utility-scale systems (<5 MW) dropping below a levelized cost of energy (LCOE) of US$0.28/kWh without incentives

- Individual project sizes are scaling rapidly, resulting in greater economies of scale and cost reductions
  - More than 10 installations greater than 20 MW in size are under development or in construction
- First Solar's 2008 development strategy for the US heightens competition as the CdTe module supplier and turnkey developer aims to be a cost leader through lowered installation costs and efficiency improvements

Module price reductions in the near term are expected to significantly drive down the cost at which PV can generate energy, accelerating the technology's market penetration

- To meet high demand in 2008, manufacturers aggressively increased supply capacity; however, now they are forced to re-negotiate supply contracts and drop prices by as much as 40% from 1H 2008 prices
- While CdTe modules currently have a 40% price advantage over C-Si technology, installation and balance of system (BOS) costs bring the installed cost of the two technologies within 10% of parity

Total PV system costs in the US vary significantly from those observed in Europe, where incentives and demand have raised the price at which systems can still be profitable (see EER's *Europe PV Cost Trends and Analysis*)

Methodology

EER has analyzed cost data from 86 PV projects completed, under construction, or in development in the US from 2002 through 2011

- System sizes included in the analysis range from 100 kW to 30 MW

Module price forecasts were developed based on the following considerations:

- Conversations with developers, manufacturers, and secondary research
- Cost profiles of projects announced for 2009 and 2010, and historic module price data
- Two technologies were considered: Cadmium Telluride (CdTe) and crystalline silicon (C-Si)

Levelized cost of energy was calculated based on the following assumptions:

- High and low resource scenarios derived from estimates of PV project production in the US Southwest (e.g. Arizona) and Northeast (e.g. New Jersey)
- Cost structures for three technology scenarios; C-Si, CdTe, and C-Si with tracking systems
- Capital cost inputs based upon actual project costs
- Known power purchase agreements for reference

Installed cost breakdown was analyzed using:

- Data collected on costs of individual components including data on 20 module suppliers (C-Si and CdTe), 10 inverter manufacturers, and 23 tracker manufacturers
- Individual component costs with installed system cost breakdown as reported by developers

PV Value Chain Trends

Bottlenecks

Module bottlenecks from 2004–2008 caused by a silicon supply shortage increased development margins, encouraging system providers to enter the segment. Module supply now exceeds demand and the bottleneck is easing

Global credit crisis is reducing financing for PV projects, requiring investors' early-stage involvement in development in exchange for portion of financing margins ("build-and-sell" model no longer as feasible)

Value Chain Component

Manufacturing

- Modules (TF and C-Si)
- Inverters
- Trackers
- Other BOP

Development

Development
- Site selection
- Site lease/purchase agreements, costs
- Permits
- FIT agreements
- Grid connection (shared function with EPC company)

EPC
- Plant design, architecture
- Electrical, civil engineering
- Procurement
- Subcontractor selection
- Construction
- Grid connection (shared function with developer)

Financing
- Due diligence
- Financial engineering (solar fund or project finance)
- Insurance, taxes
- Accounting
- Sale to investors

Investment & Ownership

Investment
- Short-term investors: EPC-developers holding projects for eventual sale
- Minority investors: PV financiers selling participations in solar funds
- Long-term, majority owners

O&M
- Monitoring
- Maintenance
- Coordination with authorities when required

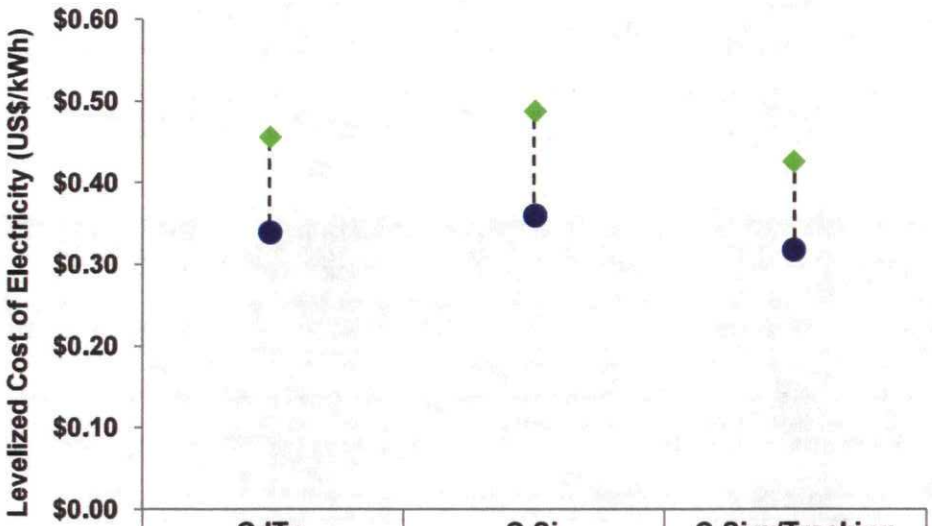
Reference Prices

Average Sales Prices:
Modules
Inverters
Trackers

Turnkey Sales Price to Investors

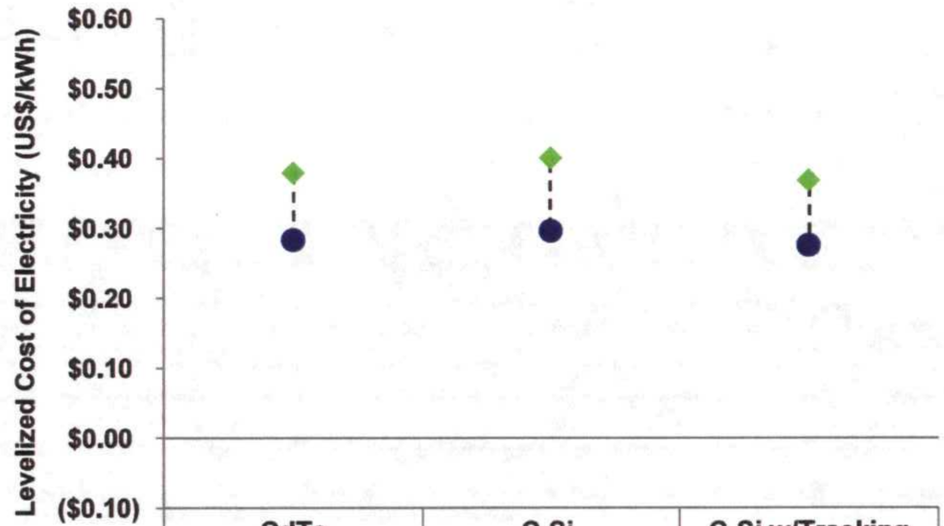
LCOE Analysis by Solar Technology

LCOE for Systems >100 kW <5 MW



	CdTe	C-Si	C-Si w/Tracking
High	$0.34	$0.36	$0.32
Low	$0.46	$0.49	$0.43

LCOE for Systems >5 MW and <50 MW



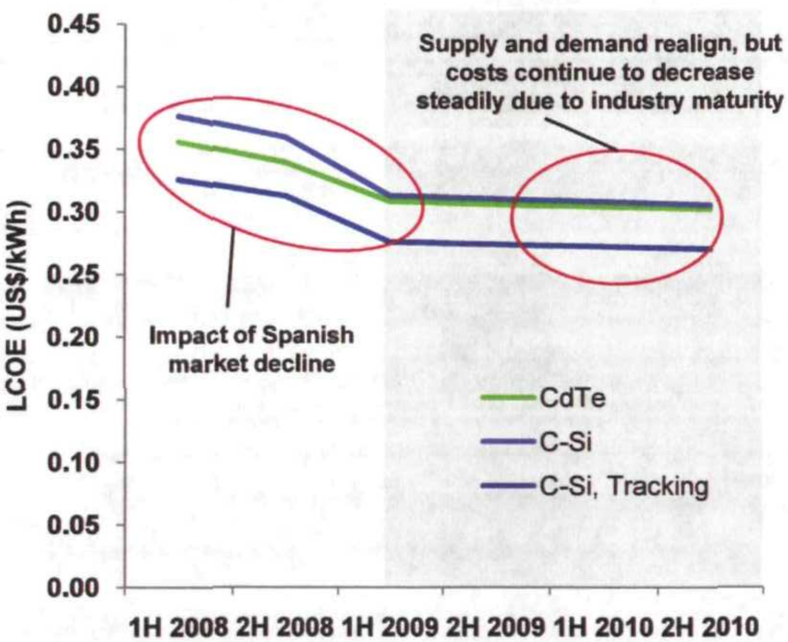
	CdTe	C-Si	C-Si w/Tracking
High	$0.28	$0.30	$0.28
Low	$0.38	$0.40	$0.37

Note: Does not include Investment Tax Credit
Source: Emerging Energy Research

Low solar resources increase the LCOE for a PV project by as much as US$0.13/kWh, while larger projects under ideal conditions generate power at US$0.28/kWh without incentives

LCOE Forecasts

LCOE Forecasts for Systems: 100 kW to 5 MW Without ITC

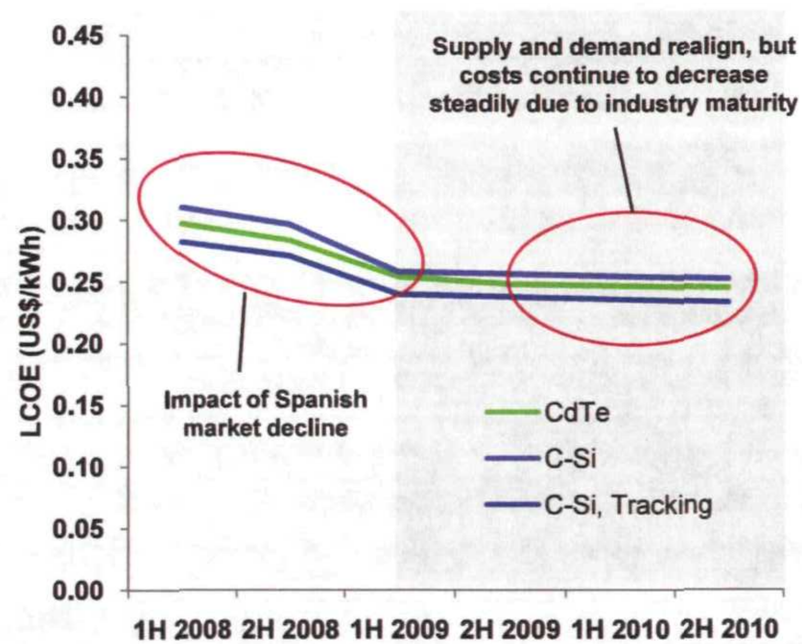


Note: LCOE calculated for high solar resource scenario

Analysis

- LCOE for commercial and small, utility-scale projects decline by as much as US$0.10/kWh as a result of a module price drop of up to 40% by 2010
- Oversupply of C-Si modules, which dominate the PV market, will be the primary driver in pushing costs down, but CdTe modules are expected to remain competitive with C-Si projects as volumes increase

LCOE Forecasts for Systems >5 MW Without ITC

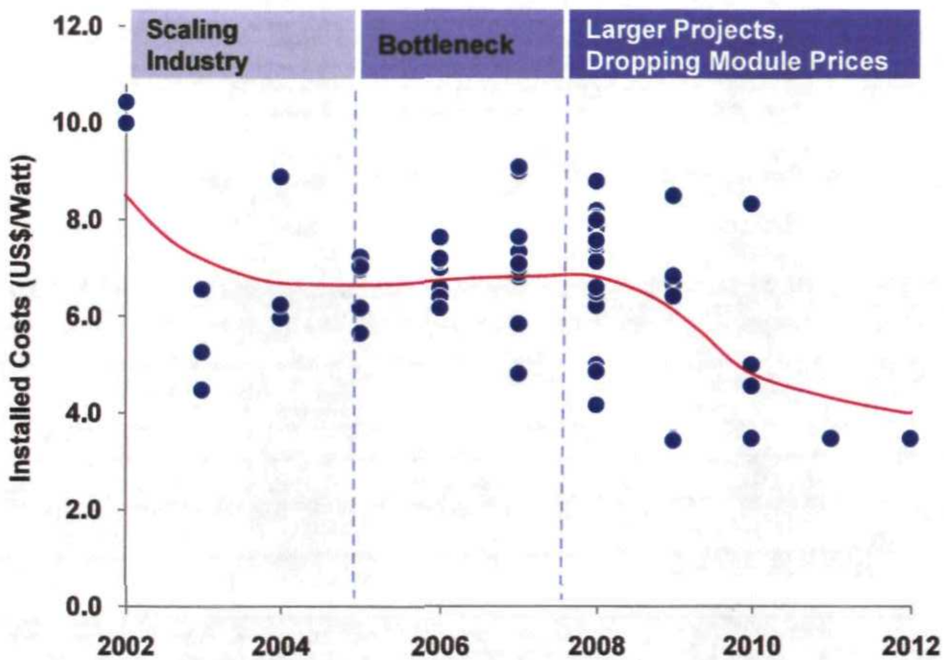


Analysis

- LCOE of medium to larger utility-scale projects (>10 MW) will drop by approximately US$0.06/kWh to US$0.08/kWh by 2010, bringing it close to US$0.23/kWh to US$0.25/kWh before the ITC or Renewable Energy Grant is applied
- Developers securing supply contracts for utility-scale projects will capture greater discounts than commercial developers

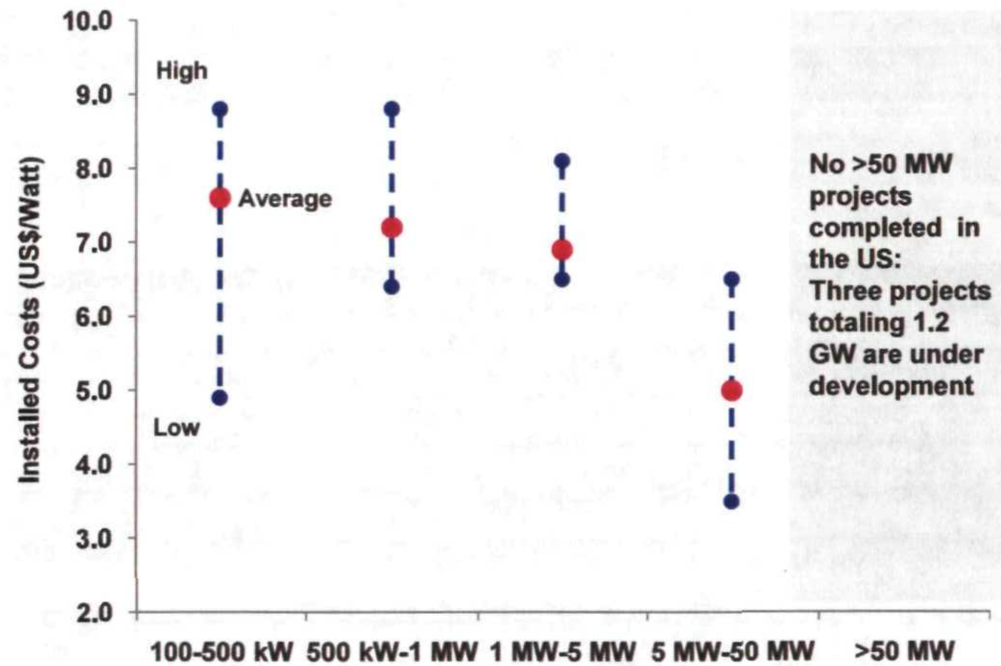
Installed Project Cost Trends

Installed Cost for PV in the US



Source: Emerging Energy Research

Current Installed Costs by Project Size



Analysis

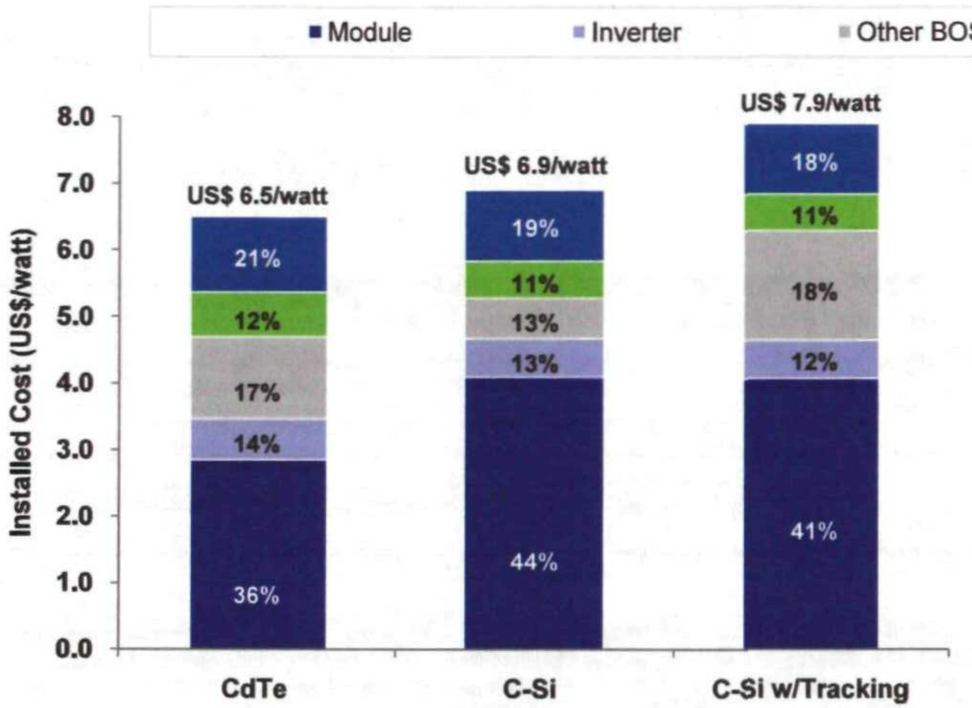
- Through 2005 the US market benefited from EU demand, forcing manufacturers to scale, thereby reducing costs
- Supply chain bottlenecks for silicon and strong demand in Spain and Germany drove module prices up from 2005 through 2008
- In Q4 2008, module prices dropped 10%, with further reductions expected in the future as Spanish demand nose dives

Analysis

- Economies of scale for PV are most evident in individual projects >10 MW in size, which are the primary focus of utilities
- The range of installed costs for commercial scale projects narrows as projects increase in size; however, larger projects face increasing siting issues including transmission and land costs for ground-based systems

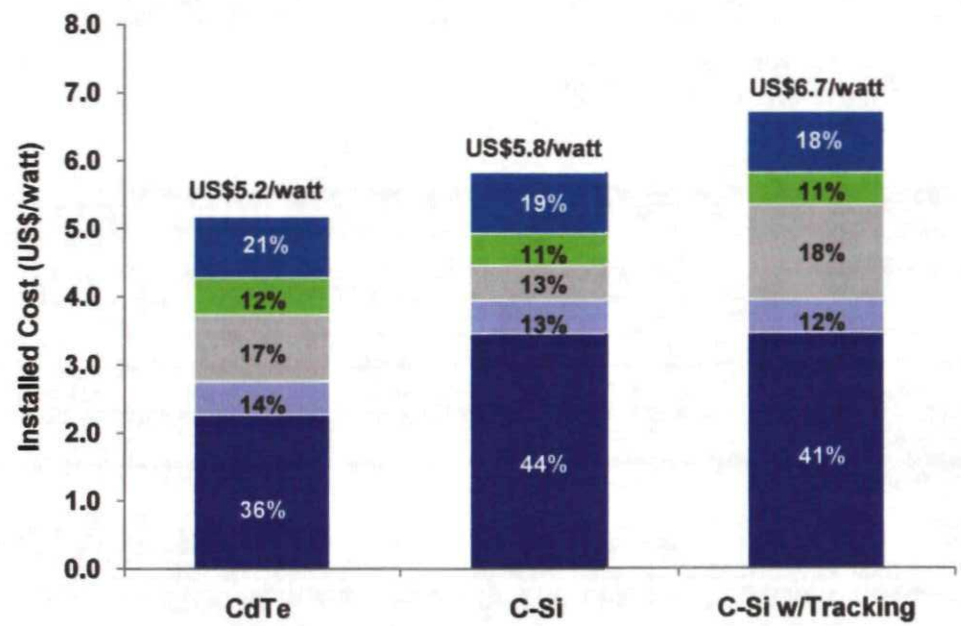
Installed Project Cost Breakdown

System Cost Breakdown: >100 kW to <5 MW



Source: Emerging Energy Research

System Cost Breakdown: >5 MW



Analysis

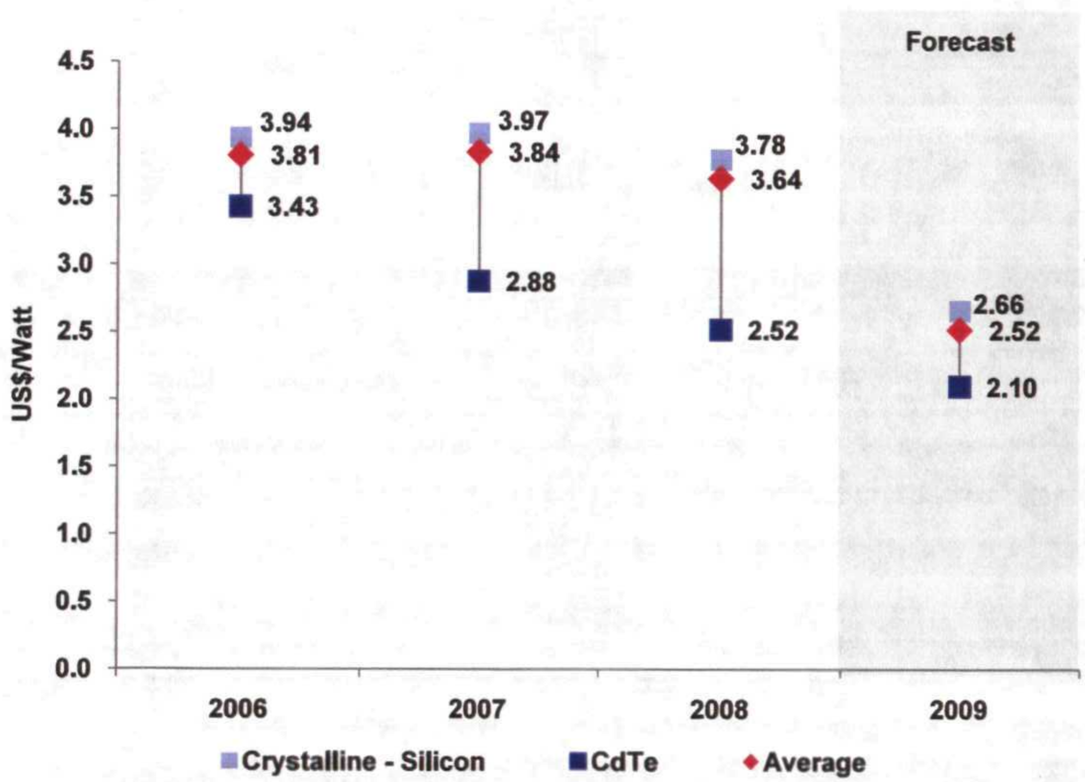
- While thin film modules offer a 10% cost advantage, increased balance of system costs (including inverters) brings CdTe projects to just under US$7/watt for large, commercial-scale projects
- Tracking systems add, on average, an additional US$1/watt to the installed cost of PV systems, and increase output 25% to 30%

Analysis

- Larger projects compress the prices for all system components through volume purchasing
- Players building larger stand-alone systems often have long-term supply agreements, giving them additional cost advantages

Module Cost Forecasts

Average Module Sales Price (US$/Watt)



Analysis

- The 500 MW cap on the Spanish market has put a major dent in 2009 global demand, just as manufacturers were scaling capacity
- Manufacturers are facing oversupply through the end of 2009, and will continue re-negotiating supply agreements to unload inventory
- Further drops will occur in 2009, bringing module prices down an additional 30% from current price levels
- Demand will rebound in 2010 and 2011 as new growth markets Italy, France, Greece, and the US offset loss of Spain demand
- Developers willing to sign large supply agreements and able to pay a 20% deposit receive a 10% to 20% discount over average module sales prices, thereby benefitting larger and well-financed players

Announced projects show module prices declining by as much as 40% by the end of 2009

LCOE Model Assumptions

Model Parameters

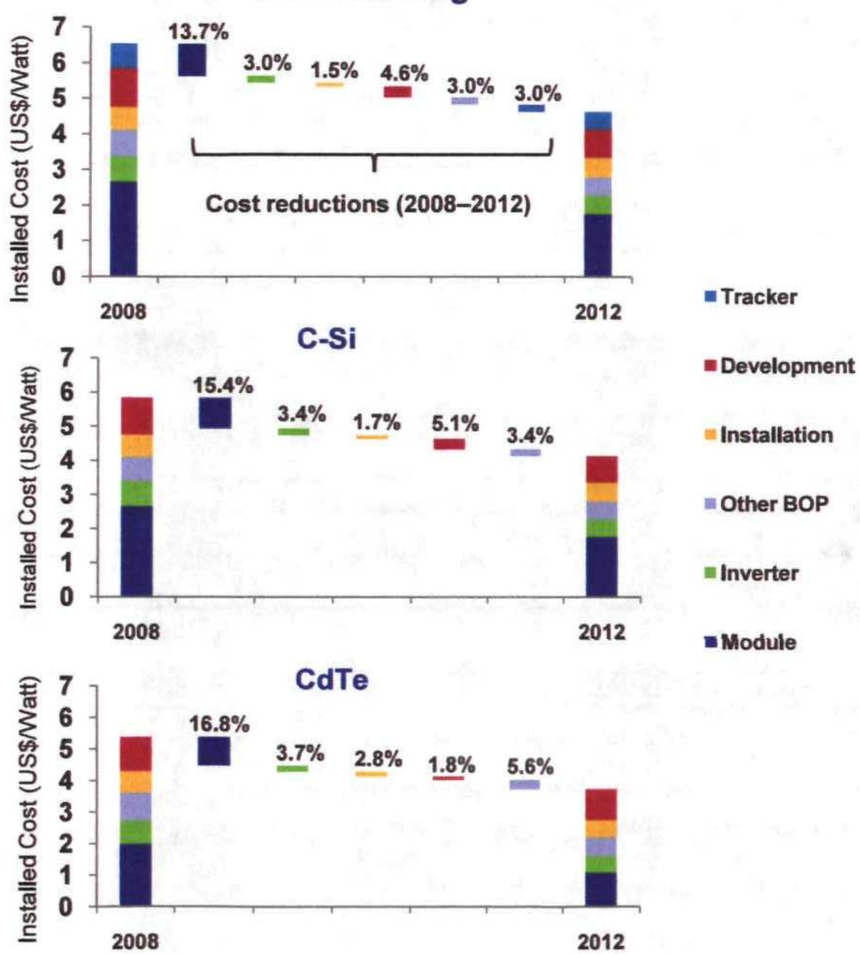
	Solar Resources /Capacity Factor		Project Lifetime	Debt/ Equity Ratio	Cost of Debt	Cost of Equity
	High	Low				
C-Si	22%	16%	25	80:20	7%	12%
Thin Film	22%	16%	25	80:20	7%	12%
C-Si Tracking	27%	20%	25	80:20	7%	12%

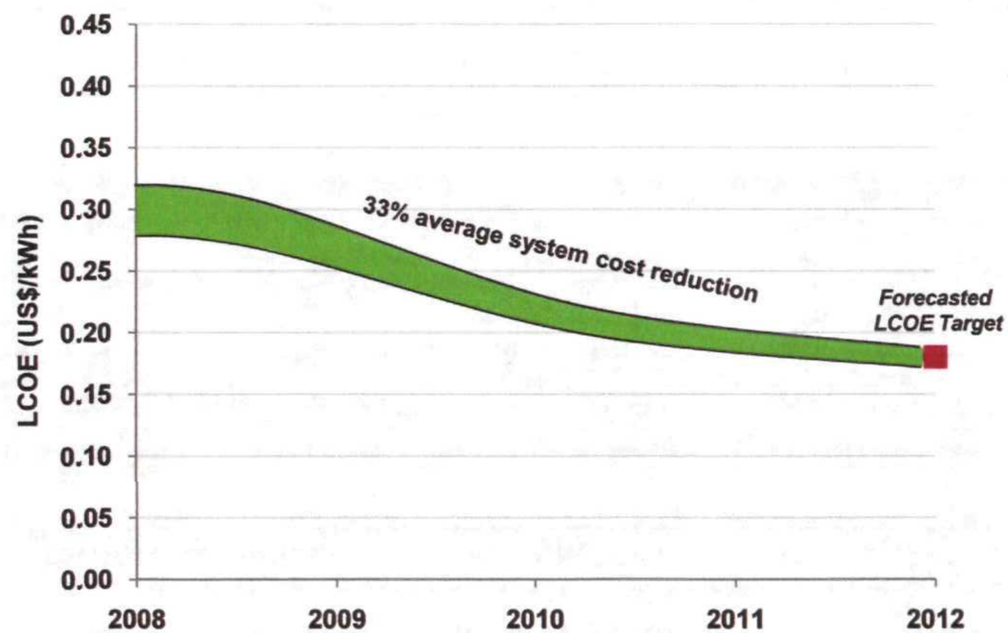
Cost Assumptions as of Year-end 2008 (US$/Watt) for Systems >5 MW

	O& M (US$/MWh) Costs	Inverter*	Installation	Development	Other BOS	Module Costs						Additional Cost of Tracker (US$/Watt)
						1H 2008	2H 2008	1H 2009	2H 2009	1H 2010	2H 2010	
C-Si	20.0	0.72	0.65	1.09	0.72	2.79	2.52	1.76	1.76	1.71	1.67	0.00
CdTe	29.0	0.72	0.90	1.09	0.90	2.08	11.87	1.31	1.31	1.28	1.25	0.00
C-Si Tracking	29.0	0.72	0.65	1.09	0.72	2.79	2.52	1.76	1.76	1.71	1.67	0.70

Note: *Inverter cost includes replacement of inverter in year 10 of project lifetime at same cost as initial inverter. Inverter costs expected to decline 10% in 2009

LCOE Outlook





Note: Assumes constant O&M costs
Source: First Solar, SunPower, SEPA, Emerging Energy Research

Average system cost reductions of one-third from 2009 through 2012—of which half will come from module price reductions—will be necessary for LCOE to fall to US$0.18 by 2012

Market Outlook

- **Stimulus package incentives such the federal Loan Guarantee Program and Renewable Energy Grants will allow larger PV projects, which may have been the most vulnerable to the current financial environment, to proceed**
- **Utilities will find it easier to push PV initiatives past public utility commissions if costs decline, encouraging them to embrace the technology**
- **Module prices will fall between 30% and 40% by the end of 2009, ultimately reducing installed system costs by US$1.00/watt to US$2.25/watt depending on technology and project size**
- **Lower PV system costs will partially offset negative impacts of the credit and tax equity markets, and potentially open up new markets**

Appendix

Additional Resources

***Gemini Leads Texas Utility Solar Market.* On Point, 13 February 2009.**
***LADWP Leverages Solar Spectrum.* On Point, 22 December 2008.**
***SunEdison Dials into Utility Demand.* On Point, 7 October 2008.**
***First Solar Expands Value Proposition.* On Point, 25 August 2008.**
***FPL Group Broadens Solar Strategy.* On Point, 6 August 2008.**
***GE Posed to Grow Solar Business.* On Point, 1 August 2008.**

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Section III
Legal Questions
(As modified during the Panel Hearing on April 16, 2009)

HREA's response to the Legal Questions is provided below.

1) **General**

a) Does Section 269-27.2(b), HRS, empower the Commission to establish a set of feed-in tariffs that compel the utility to offer to purchase power from nonfossil producers at rates, terms and conditions established by the Commission, even if those rates, terms and conditions differ from those initially proposed by the utility?

HREA Response:

Yes

b) Does the Commission have authority to mandate that the utility procure a particular quantity of nonfossil electricity, exceeding the statutory RPS requirements? Can the Commission establish deadlines? What statutes grant this authority?

HREA Response:

Yes and Yes. See 269-27.2(b) as follows:

"(b) The public utilities commission may direct public utilities that supply electricity to the public to arrange for the acquisition of and to acquire electricity generated from nonfossil fuel sources as is available from and the producers are willing and able to make available to the public utilities, and to employ and dispatch the nonfossil fuel generated electricity in a manner consistent with the availability thereof to maximize the reduction in consumption of fossil fuels in the generation of electricity to be provided to the public. To assist the energy resources coordinator in effectuating the purposes of chapter 201N, the public utilities commission may develop reasonable guidelines and timetables for the creation and implementation of power purchase agreements."

Clearly, 269-27.2(b) provides the ability of the Commission to require the utility to acquire nonfossil sources and to establish reasonable guidelines.

c) Is the Energy Agreement legally binding on any one? In what way? Who could sue whom for noncompliance?

HREA Response:

No

d) Does the Commission have authority to adopt FiTs in this proceeding without having completed a proceeding on Clean Energy Scenario Planning?

HREA Response:

Yes. Refer to our response to b) above.

e) Under a FiT regime, will there still be a need for a contract between seller and the utility buyer? What form would these contracts take? What seller's obligations should be covered under these contracts?

HREA Response:

Yes. The contract form can be the Tariff, assuming that all interconnection requirements and all relevant terms are included in the Tariff docket. This would preclude the need to have a separate interconnection agreement.

f) Assuming there are contracts associated with FiT sales, what is the Commission's statutory obligation to review these contracts? What are effective procedures to expedite Commission review?

HREA Response:

HREA does not believe there is necessarily a statutory obligation for the Commission to review FiT tariffs. Fit tariffs are similar to net metering agreements, which we understand do not undergo Commission review and approval. To be clear, once the Commission approves a FiT tariff with standard prices and terms and conditions, there may not be a need for Commission review. We assume here that purchase prices and the terms and conditions are not subject to negotiation.

Thus, HREA sees this issue as an area for management discretion. For example, the Commission could review the initial FiT Agreements, and then leave the review to an Independent Oversight Manager do the subsequent reviews. Or the Commission could delegate the review authority to the Independent Oversight Manager. And the Commission could leave the review authority to the utility. HREA prefers one of the first two options.

Section III
Legal Questions
(As modified during the Panel Hearing on April 16, 2009)

2) Cost

a) Does HRS § 269-27.2 impose any limit on total cost? For example:

i) Does the phrase "maximize the reduction in fossil fuels" in Section 269-27.2(b) allow the Commission to establish a quantity goal, determine the rate necessary to satisfy that goal, and impose that rate regardless of how high the rate is and regardless of total cost?

HREA Response:

Yes, given our "plain reading" of HRS § 269-27.2. Perhaps the statute would be more clear if the "may" was a "shall." There is also the RPS statute (HRS § 269-92) as potentially amended, i.e., assuming the Governor signs into law HB 1464 from the 2009 legislative session, which will increase the RPS to 40% by 2030, and redefines the technologies eligible under the RPS. Perhaps the real question is whether the bill is needed? In the case of the latter, we would say yes, in the case of the former, we are not sure.

ii) Does the "maximize" phrase mandate that result?

HREA Response:

HREA's opinion is that the Commission has the discretion to require certain utility actions, for example, in support of our RPS law. Thus, we are not sure, in this case, if it is important to distinguish between the two terms "maximize" and "mandate."

iii) If you believe the "maximize" phrase mandates that result, what effect does the discretionary term "may" have on the Commission's obligation?

HREA Response:

See our response to ii) above.

iv) Can the Commission determine a required quantity for the utility to purchase, and then set the rate at whatever level is necessary to attract that quantity? Would such a rate necessarily satisfy the just and reasonable standard?

HREA Response:

These are two quite different questions. The answer to the first question is "yes," given our responses above to i) and ii). We believe the answer to the second is also a "yes." Referring to the guidance from HRS § 269-27.2 (as we also did in our response to Issue IV in our RFSOP) which is inserted below:

> "(d) Upon application of a public utility that supplies electricity to the public, and notification of its customers, the commission, after an evidentiary hearing, may allow payments made by the public utility to nonfossil fuel producers for firm capacity and related revenue taxes to be recovered by the public utility through an interim increase in rates until the effective date of the rate change approved by the commission's final decision in the public utility's next general rate proceeding under section 269-16, notwithstanding any requirements to the contrary of any other provision in this chapter or in the commission's rules or practices; provided the amount recovered by the utility and the amount of increase in rates due to the payments for firm capacity and related revenue taxes to be charged to the consumers of the electricity are found by the commission to be:
> (1) Just and reasonable;
> (2) Not unduly prejudicial to the customers of the public utility;
> (3) Promotional of Hawaii's long-term objective of energy self-sufficiency;
> (4) Encouraging to the maintenance or development of nonfossil fueled sources of electrical energy; and
> (5) In the overall best interest of the general public."

HREA observes that the statute appears to give the Commission a lot of latitude, e.g., rates that are "<u>just</u> and <u>reasonable</u>," and "not <u>unduly</u> prejudicial to the customers of the public utility" when seeking to maximize or optimize the policy objectives (emphasis added).

b) Regardless of any statutory limit on cost, does the Commission have authority to establish a dollar limit on the cost of utility acquisition of nonfossil electricity pursuant to a FiT? What statutes grant this authority?

HREA Response:

With the signing into law of HB 1270 (passed in 2009 legislative session) as Act 50 by the Governor, "avoided cost" is no longer a CAP on the cost that the utility can pay for renewable energy in meeting its RPS. While this change in statute provides the opportunity to encourage "higher-costing" renewable technologies, HREA believes the Commission has the discretion under HRS § 269-27.2 to impose dollar limits, if it believes the rates would NOT be "just and reasonable" or the rates would be "prejudicial to the customers of the utility."

c) Does this authority to establish a dollar limit apply only to acquisition above the quantities required by the RPS statute?

HREA Response:

No.

3) Sellers' Legal Rights

a) PURPA

i) Does a nonfossil developer have an existing statutory right, under state law or PURPA, to a negotiated PPA? If so, does that right continue even if the Commission establishes FiTs that constitute utility offers to buy at a stated rate, or can the Commission make the FiT the exclusive means by which nonfossil producers sell to the utility? Put another way, if there is a FiT applicable to a particular seller, may the Commission authorize (or forbid) the utility to negotiate a PPA on terms that vary from the FiT?

HREA Response:

Yes, we believe the PURPA obligation still stands, at least in terms of a QF's right to negotiate a contract with the utility. Initially, HREA's position in the FiT docket was for developers to have both options, i.e., a FiT or a non-bid PPA. Now we can see some administrative and policy advantages to limiting the choices to just the FiT. However, we are not persuaded that this position would hold up if litigated.

Perhaps it could if one could argue that the FiT is a type of PURPA contract, especially one in which both Parties are in agreement. However, HREA supposes that there could be a Party that might just wish to go with a non-Bid PPA.

ii) Can the Commission substitute a FiT for Schedule Q, as a means of complying with PURPA? What type of issuance from the Commission would be necessary to demonstrate PURPA compliance?

HREA Response:

Our response is the same as for item i) above, assuming that you replace the terms "non-Bid PPA" with "Schedule Q contract."

b) Does HRS § 269-27.2 create any legal rights in sellers of nonfossil power? For example:

i) Does the phrase "just and reasonable rate" in HRS § 269-27.2(c) mean "just and reasonable" to the seller, or only "just and reasonable" to the consumer? That is, does the phrase "just and reasonable rate" allow a seller to contest a Commission-established FiT on the grounds that the rate is too low or that non-rate terms and conditions are unfavorable?

HREA Response:

Yes. HREA notes that we have been using the term "fair" instead of "just and reasonable" when discussing the Seller's side of the bargain. Specifically, a "fair" rate to the Seller would allow the Seller the opportunity to earn a reasonable rate of return on his investment. HREA believes that the utility and the Commission will get timely feedback as to the "fairness" of the payments rates. Specifically, if a FiT rate is too low, nothing will happen, i.e., no one will apply for FiT agreements. On the other hand, if the FiT rates are high the queue will fill up faster than rapidly. Thus, HREA suggests if the FiT rates are "just right," the queue will fill up rapidly, which is what we want.

In response to the second question, HREA doubts that any potential FiT provider will "contest" that a FiT rate that is too low or that a specific non-rate term is unfavorable, as a more productive approach would be to provide feedback to the Commission and request a re-evaluation of the FiT rate.

In this regard, HERA suggests that the Commission ensure that the application process provides adequate opportunity for feed-back from potential FiT providers.

Section III
Legal Questions
(As modified during the Panel Hearing on April 16, 2009)

ii) On what specific grounds could the seller contest the rate? That the rate produces a return on equity too low to attract sellers? How would the seller prove this case, to the Commission and to reviewing courts? What data would the Commission have to rely on to insulate its rate decision from judicial reversal? What evidentiary burden does the seller have, to supply facts to the Commission so that the Commission has the necessary factual support for its decision?

HREA Response:

HREA finds this line of questions to be quite interesting, especially if you asked the same questions with respect to PURPA rights. In that case, we understand that QFs have the right to petition the Commission regarding contested issues in negotiations with the utility.

With respect to FiTs, perhaps a seller might wish to contest specific issues such as payment rates or the broader issue as to whether the FiT is designed properly to meet state energy goals. HREA is inclined to suggest the following as a first step to insulate the Commission from possible litigation. Specifically, as much as HREA would dread any additional delays in publishing a FiT tariff, the Commission might consider putting the "approved FiT tariff" out for a general public review. HREA is not sure whether there is a precedent for this in other FiT proceedings, but on the surface it would be the equivalent of the utility holding a bidder's conference on a RFP.

iii) If the Commission declined to establish any FiT rates, but instead authorized the utility to self-produce or purchase renewables as the utility deems appropriate, would the sellers have any legal claim against the utility or the Commission? If the answer is no, then do the sellers have any legal right to contest a Commission-established FiT?

HREA Response:

HREA has to assert this a rather diabolical question. Notwithstanding that assertion, the simple answer to the first question is "yes," as HREA believes a seller or sellers clearly have a right, regardless of any merits, to litigate any decision made by the Commission.

c) Assuming the Commission establishes FITs, may the Commission authorize (or forbid) sellers with existing PPAs to terminate the PPA and enter into an agreement under the FIT? Under what conditions? With what Commission involvement?

HREA Response:

Yes. HREA believes the Commission has the legal right to authorize sellers with existing PPAs to terminate the PPA and enter into an agreement under a FiT. HREA expects that the FiT terms and conditions would be designed in a manner that reasonably protects the interests of the utility, including the right of the utility to pass on FiT payments through the ECAC or through some other mechanism, so there should be no harm to the utility in allowing sellers to terminate PPAs and move to the FiT. Assuming the Commission authorizes this legal right in the FiT, there should be no need for Commission involvement other than a legal notice to the Commission that a seller has elected to exercise such right.

d) Hawaii statutes prohibit undue discrimination in the provision of utility service. How does that prohibition apply in the context of FiTs? For example:

i) Can there be different rates for different technologies/sizes/islands: What factual differences are necessary to justify rate differences?

HREA Response:

HREA believes, just as utility rates differ per island and under PURPA avoided costs also differ from island to island, there are precedents for the FiT rates to differ. However, we believe a more persuasive argument for payment rate differentiation is the pricing criteria assumptions that rates should be cost-based. Clearly, the cost to install and operate projects differs by island due difference in development costs, shipping of equipment, local labor and materials and other costs, such as project size. Thus, these cost differences justify rate differences.

ii) Can there be negotiated PPAs that make use of FiT rates but that vary from each other in other terms and conditions?

HREA Response:

Yes, unless the Commission decides to replace non-Bid PPAs with FiTs.

iii) Can there be a negotiated PPA for projects that qualify under a FiT?

HREA Response:

Yes, unless the Commission decides to replace non-Bid PPAs with FiTs.

4) Utility Role

a) Does the Commission have the power to restrict the utility's ability to build its own nonfossil generation, such as requiring the utility to refrain from building whenever there is a viable independent seller offering to sell? What findings must the Commission make to support such a restriction?

HREA Response:

HREA believes the Competitive Bidding Framework should apply in this case. HREA understands that the utility must identify any new generation needs in IRP, assuming for the moment that IRP continues and the Competitive Bidding Framework is revised accordingly. The utility must also indicate if the new generation needs are to be exempted from competitive biding. Either way, HREA believes the utility must either bid out the project, possibility as a turnkey installation, or obtain approval for exemption.

b) Same question as above, but applied to utility affiliates that sell renewable electricity to another utility affiliate.

HREA Response:

HREA's response to this question with respect to utility affiliates, whether regulated affiliates or unregulated affiliates, is the same as for a) above.

Section IV
Additional Questions from the Panel Hearing
(Received on May 11, 2009 from NRRI)

In the FiT hearing, parties were asked by NRRI to provide additional information on the following issues:

1. We asked developers if they have been able to use or monetize accelerated depreciation.

   HREA Response:

   Bonus Depreciation (50% in year 1) has only been extended to projects on-line in 2009, so it likely won't apply to FIT projects. Most developers won't have sufficient earnings to be able to monetize the MACRS accelerated depreciation from projects of this size against their own tax liabilities. Monetizing the losses through project ownership transfer (sale leasebacks and partnership flips) is currently limited by a lack of appetite in tax equity markets. Without ownership transfer to a tax hungry partner, developers face the prospect of self sheltering the losses, the value of which are diluted by the time value of money across the landscape over which they are utilized, thus lowering project returns.

2. Should the FiT be extended to incremental expansions of existing projects? HECO indicated technical or administrative difficulty in determining how much power would come from incremental additions. We asked HECO and developers to describe to what extent would this be possible?

   HREA Response:

   HREA is examining this issue and intends to provide a response in its reply brief.

3. What reliability standards could HECO craft to add transparency, if not predictability, to HECO's reliability determinations for FiT applicants?

   HREA Response:

   HREA appreciates the Commission's recognition of the current lack of transparency in the current procurement process. The examination of reliability standards is complex, but HECO should start by clarifying what constitutes grid system reliability, and the standards that should be developed to meet system reliability.

4. We asked HECO if it would be possible to provide better circuit-level data to developers so that they can predict where IRS studies would be triggered? HECO indicated that they only have SCADA data for 20% of circuits. This issue may be outside the scope of the FiT, but is something that the utility and developers should address to improve the FiT's implementation.

HREA Response:

HREA agrees that better circuit-level data should be provided to developers. HREA requests that the Commission require HECO to provide circuit-level data by two years after approval of the FiT program by the Commission.

5. We asked HECO to what extent remote control of projects would or would not trigger accounting issues. The remote control requirements of Rule 14 may be outside the scope of the FiT but addressing them could improve the FiT's implementation.

HREA Response:

Not required, as the question is directed to HECO.

6. Developers were asked to provide examples of terms following the completion of PPAs and the amount of residual value.

HREA Response:

Residual value will often be mentioned in a PPA as an End of Term value but is typically subject to a "higher of Fair Market Value or End of Term" evaluation at the end of the term. The value placed on the equipment post-PPA or post-FIT contract is a reflection of the developer's perspective on power revenue/risk and costs after the end of the term. More importantly, most banks in the current environment are not going to lend against the residual value of the system so developers need to contribute equity to the project to cover financing gaps beyond the coverage provided by banks. Residual calculations are likely to be held as proprietary by developers.

7. HECO was asked if there were accounting implications (e.g. imputed debt) for whether the FiT was technically a service contract or a tariff on file with the Commission. HECO indicated that it were not sure and would examine the matter.

HREA Response:

Not required, as the question is directed to HECO.

8. Life of the Land and other developers were asked what process the Commission should use in periodic updates to add technologies. They were also asked how the Commission should be kept abreast of relevant technology and industry developments.

HREA Response:

HREA suggests that the Commission consult with the U. S. Department of Energy and the Hawaii Natural Energy Institute for assistance on periodic technology updates. That said, HREA also suggests that technology updates be timed to coincide with the review of the overall FiT program.

<u>CERTIFICATE OF SERVICE</u>

The foregoing HREA FSOP was served on the date of filing by Hand Delivery, first class mail, postage pre-paid, or electronically transmitted to each such Party as follows.

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DATED: Honolulu, Hawaii, June 12, 2009